EXHIBIT 48

ANNEXED TO THE DECLARATION OF HOWARD J. STEINBERG IN SUPPORT OF OPPOSITION OF PLAINTIFF THE NANCY SUE DAVIS TRUST TO MOTIONS OF NEW DAVIS DEFENDANTS AND ALBERT S. CONLY, LIQUIDATING TRUSTEE, FOR SUMMARY JUDGMENT

DAVIS PETROLEUM CORP.

A MANAGEMENT BUY-OUT OF A PRIVATELY HELD NORTH AMERICAN OIL & GAS EXPLORATION COMPANY

REVISED INVESTMENT MEMORANDUM

RED MOUNTAIN CAPITAL PARTNERS LLC

JANUARY 16, 2006

IMPORTANT NOTICE TO LIMITED PARTNERS

The information in this memorandum is highly confidential. Disclosure of such information (other than to your legal, financial and other advisors) without the consent of Red Mountain Capital Partners LLC (together with its affiliates, "RMCP") is prohibited.

RMCP makes no representation or warranty as to the accuracy or completeness of the information in this memorandum. Any projection or forward-looking statement in this memorandum represents only the best, present estimation of RMCP, based upon information presently available to RMCP. Such projections and forward-looking statements are based upon assumptions about future events. Actual results may vary. RMCP disclaims all liability for the information in this memorandum.

In making your investment decision, you must rely exclusively on your own examination of the investment opportunity described in this memorandum and represent and warrant that you have such knowledge and experience in financial and business matters as would enable you to evaluate the merits and risks of such an investment and acknowledge that such an investment would be speculative and involve a high degree of risk.

By accepting this memorandum, you agree to the foregoing. If you do not agree to any of the foregoing, please advise RMCP as such and return this memorandum as soon as possible.

Davis Petroleum Corp.

I. Introduction

The management buy-out of Davis Petroleum Corp. ("DPC" or the "Company") presents an opportunity to invest in a highly regarded North American oil and gas exploration company with a unique business model at an attractive price. The transaction will allow the Davis Family Trusts to redeem or roll their interests in DPC and will provide $125.3mm of new capital for the business. The Company has recently discovered substantial offshore oil and gas reserves that require significant completion and development capital expenditures. DPC expects these new offshore wells to begin production in 2006 and 2008 and the Company to be cash flow positive (after all capital expenditures) as of mid-2006. RMCP has a long history of involvement with DPC, a high level of confidence in DPC's management and extensive industry experience. RMCP has the opportunity to invest alongside Evercore Capital Partners and Sankaty Advisors (an affiliate of Bain Capital) each of whom also have significant industry experience and in-depth knowledge of the Company and management. The following analysis is based on our due diligence and best judgment. Certain terms are subject to adjustment prior to close.

Transaction Summary

Target	Davis Petroleum Corp.
Seller	Davis Family Trusts
Transaction Description	Management Buy-Out
Security Description	4.4% PIK Junior Subordinated Convertible Debt and Common Equity
Anticipated Closing Date	January 31, 2006
Total Capital Commitment	$192.9 – 197.9mm
RMCP Capital Commitment	$38.6 – 39.6mm
RMCP Capital Commitment as a % of Total	20%
Lead Investor (60%)	Evercore Capital Partners
Additional Investor (20%)	Sankaty Advisors

II. Company Overview

DPC is a privately held independent oil and gas exploration company headquartered in Houston, Texas, with operations in Texas, Louisiana, Oklahoma, the Rockies and the Gulf of Mexico ("GOM"). DPC was founded by Jack Davis in 1939 and was built up by Jack's son, Marvin, in the 1960s and 1970s to become one of the largest independent oil and gas exploration companies in the United States. In the early 1980s (as oil prices peaked at approximately $40 per barrel), Marvin sold substantially all of the Company's assets and generated over $800mm in sale proceeds. During the last decade, Marvin and his son, Gregg, rebuilt the business by moving its headquarters to Houston, recruiting new talent (with an emphasis on offshore exploration) and committing capital to the acquisition of extensive seismic data and leasehold interests. DPC today consists of a world-class team of explorationists, a substantial inventory of

exploration prospects and significant onshore and offshore reserves. Marvin passed away in September 2004 and Gregg became DPC's chief executive officer, having been President of DPC since 2002. No other members of the Davis family are involved in the business. DPC has approximately 50 employees with offices in Houston and Denver.

DPC's core business is to generate sophisticated oil and gas exploration prospects (which have substantial intellectual property value) and to market such prospects to industry partners on a promoted basis. DPC invests in people (geologists, geophysicists, engineers and landmen), technology, seismic data and leasehold interests in order to generate marketable prospects. Typically, in return for the rights to DPC's prospects, industry partners will agree to reimburse DPC for its prospect development costs (with a small profit margin), pay for the full cost of the exploratory well, and give DPC a carried interest (typically 25%) in the well which, upon a discovery, will convert into a working interest of equal percentage in the associated reservoir. DPC's business model minimizes its exposure to "dry hole" risk and limits capital expenditures to the completion and development of its working interest in identified reservoirs for which there is a known and compelling IRR. The exact parameters of DPC's promotional arrangements with its industry partners vary in the different regions in which it operates, but the overall risk mitigation philosophy is consistent across regions and a legacy of Marvin's management style.

DPC's business model allows it to drill a large number of wells for a company of its size. In 2004 and 2005, DPC drilled 10 and 19 wells, respectively, with a success rate of 41%. DPC has the capacity to operate its own wells; however, when it sells a majority stake in a prospect to an industry partner, it is more likely that the industry partner will operate the well in close coordination with DPC. DPC currently has 33 wells in production of which it operates 11. In addition, the Company currently has 12 exploration prospects that are scheduled for drilling in Texas, Louisiana, Oklahoma, the Rockies and the GOM and 31 prospects that are in various stages of development and marketing. DPC also holds substantial inventories of valuable seismic data and leasehold interests to support its exploration activities.

DPC's most valuable resources are its highly regarded exploration teams of geologists and geophysicists and its engineers and landmen. The offshore exploration team is formerly of Vastar Resources (a subsidiary of ARCO) where they made major discoveries in the GOM that are now being developed by BPAmoco. The onshore teams consist of a core of veteran DPC employees who worked with Marvin and discovered legendary fields in Texas and the Rockies along with talented newcomers who have joined DPC during the past ten years from well known independent exploration companies.

DPC's senior management consists of Gregg Davis (President and CEO), George Canjar (Executive Vice President and COO), and Mike McGuire (Executive Vice President – Rocky Mountain Region). A new CFO will be recruited in connection with the transaction. An overview of DPC personnel is included in Appendix A.

III. Certain Operating Challenges and Mitigating Factors

DPC is exposed to certain operating challenges and has adopted various strategies to mitigate their effects. Such challenges include:

Liquidity

As a family-owned company, DPC historically has been thinly capitalized and has relied upon the Davis family for capital infusions when necessary. The Company has raised as much secured debt financing as possible and, in the absence of new capital, is in technical default under its senior and subordinated loan

agreements. Production interruptions in the GOM and Texas have exacerbated DPC's liquidity situation. The transaction will provide new capital in an amount sufficient to address the Company's liquidity issues, cure all technical defaults under its credit agreements and allow the Company to execute its business plan.

Capital Expenditure Requirements

DPC's oil and gas discoveries generate substantial capital expenditure requirements. While DPC minimizes capital expenditures associated with its exploration activities by recovering most of its prospect development costs and avoiding exploratory well costs, it must cover its share of completion and development costs in order to maintain its working interests in producing wells. DPC's offshore activities magnify this challenge due to the very large capital expenditure requirements for offshore wells and long lead times to first production. DPC manages its exposure to capital expenditures by limiting or selling down its working interests in projects and considering project financing alternatives.

Hurricanes

DPC is exposed to potential facility shut downs and equipment damage resulting from hurricanes in the GOM and the Texas and Louisiana Gulf Coast. For example, production at Bellis was interrupted in August 2005 and will not resume until mid-2006. DPC has business interruption and loss of use insurance to help protect it from such events. However, any interruption in oil and gas production can lead to short-term liquidity challenges.

Rig Procurement

DPC can face difficulty in securing rigs to drill prospects in a timely manner. In the GOM and Oklahoma, access to rig slots is part of the criteria considered when selecting an operating partner. In Texas, Louisiana and the Rockies, the Company enters into a small number of long term rig contracts to control day-rate inflation and to be able to barter rig slots for access to others' drilling arrangements. The Company currently has entered into one such contract on the Gulf Coast and is currently negotiating two more rig contracts, one in the Rockies and another on the Gulf Coast.

Environmental Liabilities

DPC limits its exposure to environmental liabilities by maintaining a highly professional and experienced staff and implementing best practices to avoid such liabilities. These best practices are augmented by insurance and extensive due diligence in any facility or land acquisition. The Consortium's environmental engineering consultant, Conestoga Rovers & Associates, completed a detailed analysis of the Company's current environmental exposure and did not find any material issues.

Regulatory Matters

DPC's ability to generate prospects can be adversely affected by the length of time required to receive all necessary regulatory approvals. In addition, changes to the current regulatory environment could have an adverse effect on the Company's ability to generate prospects. The Company is familiar with the regulatory environment in which it operates and focuses on generating prospects in areas with acceptable regulatory requirements.

Offshore Lease Sales

DPC secures its GOM leases through a competitive sealed bid process organized by the U.S. Government. This process can lead to high prices and the potential to be shut out in auction, thereby restricting the Company's ability to generate offshore prospects. DPC approaches this process by conducting detailed bid analyses that statistically capture historical behavior by area and competitor and securing bid partners. An effective bid partnership can reduce competition and allow for stronger and more bids per lease sale. In that regard, DPC expects to enter into a three year bidding partnership with Energy Partners Ltd prior to closing the transaction. As an alternative to competitive bidding, the Company also attempts to secure "farm-ins" from existing leaseholders prior to the expiration of their leases. This approach was used to generate the Clipper prospect.

Employee Retention

Retention of DPC's experienced and highly regarded oil and gas explorationists in a very competitive environment is essential to the execution of its business plan. The Company retains its key employees through non-compete agreements and overriding royalty interests in DPC's producing wells. The Consortium will also grant restricted common stock and issue stock options to management and key employees as additional retention incentives.

Litigation

DPC, in the ordinary course of its business, faces potential litigation with regard to environmental impact and potential harm to the land on which it is conducting its oil and gas operations. The Company has insurance to help protect it from such lawsuits. Presently, the Company is not involved in any material litigation (other than the Raynes lawsuit mentioned below) nor is it aware of any such potential lawsuits.

IV. Recent Developments

In the past two years, DPC has discovered three significant reservoirs of oil and gas in the GOM (Bellis with estimated reserves of 20-40mm BOE, Lorien with estimated reserves of 15-25mm BOE, and Clipper with estimated reserves of 10-30mm BOE) that require substantial completion and development capital expenditures in order for the Company to maintain its working interests of 15%, 10% and 30%, respectively, in each reservoir. DPC has already incurred over $26mm of such capital expenditures and expects to spend an additional $33mm in 2006. These capital expenditures have compelling IRRs and the oil and gas production associated with these offshore reservoirs will have a disproportionately positive impact on DPC's EBITDA over the next several years. Bellis went into production in 2005 (which was interrupted by hurricanes Katrina and Rita and will not resume until mid-2006) and Lorien and Clipper will go into production in 2006 and 2008, respectively. The Company is also actively engaged in generating new offshore prospects in connection with upcoming lease sales in the GOM. The cost of generating such prospects is substantial and is expected to be $16mm in 2006.

Following Marvin's passing in September 2004, the Davis family decided not to commit the substantial amount of capital necessary to fund DPC's ongoing prospect generation costs and completion and development expenditures and authorized Gregg to pursue a management buy-out of DPC. As noted above, in the absence of new capital from the family, DPC faces significant liquidity challenges and is in technical default under its credit agreements.

In January 2005, Gregg and DPC engaged RMCP in an advisory capacity with respect to a potential management buy-out. After securing an independent valuation from Richardson, Barr & Associates, soliciting detailed proposals to acquire the Company from Evercore Capital Partners, Sankaty Advisors, Carlyle/Riverstone and Constellation Energy, engaging an independent director for DPC and receiving a fairness opinion from Jeffries & Co., the Davis family decided to sell control of the Company to a private equity consortium consisting of Evercore, Sankaty and RMCP (collectively, the "Consortium").

Evercore, acting on behalf of the Consortium, entered into an exclusivity agreement with DPC on October 26, 2005, and is currently conducting confirmatory due diligence and preparing definitive documentation for the transaction. All material terms have been agreed; the exclusivity agreement has been extended until January 31, 2006; and the transaction is expected to close on January 31, 2006. Evercore has engaged South River Exploration and Deloitte & Touche as engineering and accounting consultants and Jones Day as legal counsel to assist in the Consortium's due diligence.

On September 13, 2005, Patricia Davis Raynes, Marvin's eldest daughter, filed a lawsuit against Marvin, all of the other Davis family members and certain related parties (including DPC) alleging, among other things, breach of fiduciary duties and fraud over a thirty year period with respect to her trust. The Davis family has rejected the allegations. The Consortium has no view on or interest in the validity of the allegations outlined in the Raynes lawsuit and will require her consent to the transaction and a full release and/or indemnification from any further claims against DPC as a condition of closing.

V. Transaction Partners

Evercore Capital Partners is the private equity arm of Evercore Partners and has approximately $1.2 billion under management. Evercore has significant experience in the oil and gas industry having invested $59mm in Energy Partners Ltd ("EPL"), an independent oil and gas exploration and production company operating in the GOM, in 1999. EPL went public in 2000 and currently has a market value of over $900mm. Evercore helped EPL to establish alliances with energy companies with which Evercore had pre-existing relationships, to develop its hedging program and to recruit new board members. Evercore also acted as a strategic advisor in executing property acquisitions, the acquisition of Hall-Houston Oil Co. (a business very similar to DPC) and various financings. Three partners of Evercore are actively involved in the DPC acquisition: Austin Buetner, the President of Evercore Partners and head of Evercore Capital Partners; Will Hiltz, the former head of the energy and power investment banking groups at Salomon Smith Barney and Dillon Read; and Ciara Burnham, who has led the due diligence and negotiations for Evercore and the Consortium.

Sankaty Advisors is the credit affiliate of Bain Capital and has approximately $12 billion under management. Sankaty provided DPC with $23 million of subordinated debt financing in 2004 and a $20 million bridge loan in 2005 in anticipation of an equity transaction and will allow the Consortium to assume its subordinated debt financing. As DPC's current mezzanine lender, Sankaty has a deep knowledge of the Company and a strong relationship with its management. Stuart Davies, a partner of Bain Capital and Sankaty Advisors, led the mezzanine financing for DPC and is responsible for the DPC acquisition.

RMCP acted as an advisor to DPC and its management in connection with arranging bridge financing and the proposed transaction. RMCP's managing partner, Will Mesdag, has been involved with DPC and its management for over five years as an investment banker at Goldman Sachs and as a senior advisor to the Davis Companies and has an intimate knowledge of the business.

VI. Transaction Overview

The Consortium has agreed to acquire $125.3mm of junior subordinated secured convertible debt issued by the Company in order to retire a $20.3mm bridge loan, to fund working capital, to provide management with restricted stock incentives and to provide funds for the completion and development of the Company's recent offshore discoveries, certain new initiatives in the Rockies and the acquisition of additional seismic data and leasehold interests. The Consortium will also acquire $72.6mm of secured convertible debt and common equity issued by the company, the proceeds of which will be used to redeem 91.2% of the Davis family members' shares in DPC. DPC's management and employees have an opportunity to acquire up to $5mm of stock in the transaction. The Consortium's capital requirement at closing will be between $162.9mm and $167.9mm depending upon the extent of employee investment. The Consortium will have a continuing capital commitment after closing of $30.0mm.

The convertible debt acquired by the Consortium will carry an interest rate of 4.4% that will be payable in kind. As a debt instrument, the interest will accrue and will be taxable to the holder. In order to minimize non-cash taxable earnings, the Consortium will seek to convert the interest on the convertible debt from payable in kind to current pay as soon as the Company's lenders permit and, in any event, will convert the notes into common equity as soon as is appropriate.

Sources and Uses of Capital

Sources		Uses	
Gregg Davis Equity Roll	$7.0	Gregg Davis Equity Roll	$7.0
Common Equity	36.3	Davis Family Equity Redemption	72.6
Junior Subordinated Convertible Debt	131.1	Sankaty Subordinated Debt Assumption	22.6
Sankaty Subordinated Debt Roll	22.6	Bank of America Senior Debt Paydown	20.0
Senior Debt	20.0	Sankaty Bridge Financing Paydown	20.3
		Working Capital Contribution	12.2
		Transaction Fees	2.5
		Remaining Cash	60.2
Total Sources	$217.4	Total Uses	$217.4

($ in millions)

The post-money capitalization presented below assumes the Consortium invests $131.1mm in secured convertible notes and $33.8mm in common stock ($7.0mm of which is set aside as management restricted stock), Gregg rolls his equity into unsecured convertible notes (40%) and common stock (60%) and the employees invest $2.5mm in common stock. As noted above, DPC's management and employees may invest up to $5.0mm in common stock.

Capitalization

Pre-Money		Post-Money	
Davis Family Common Stock	$79.6	Gregg Davis Common Stock	$4.2
Sankaty Subordinated Debt	22.6	Consortium Common Stock	26.8
Bank of America Senior Debt	20.0	Management Restricted Stock[1]	7.0
Pre-Money Enterprise Value	$122.1	Employee Equity Purchase[2]	2.5
		Gregg Davis Convertible Debt	2.8
		Consortium Convertible Debt	131.1
		Sankaty Subordinated Debt	22.6
Sankaty Bridge Financing	$20.3	Senior Debt	20.0
Negative Working Capital	12.2	Cash	(60.2)
Pre-Money Bridge Financing	$32.5	Post-Money Enterprise Value	$157.2

DPC's post-money enterprise value will be $157mm. After the transaction, DPC will have cash in the amount of $60m that will be invested primarily in leasehold interests, seismic data and well costs to fund future growth and completion and development expenditures relating to offshore reserves. As noted above, DPC will also have the right to issue an additional $30mm of convertible notes to the Consortium on the same terms as the notes issued at closing.

Evercore, Sankaty and RMCP have committed to acquire 60%, 20% and 20%, respectively, of the convertible debt or common stock issued by the Company at closing and thereafter, net of any employee purchases. Evercore will control the board and all members of the Consortium will have board seats.

VII. Purchase and Sale Agreement

The Consortium is represented by Jones Day in Houston and the Davis Family Trusts are represented by O'Melveny & Myers in Los Angeles. The transaction will be documented through a Purchase and Sale Agreement that has representations and warranties and other material terms and conditions that are acceptable to the Consortium. The Davis Family Trusts have agreed to assume certain pre-closing liabilities related to their ownership of and authority to transfer shares, historical income taxes and the Raynes lawsuit. The Trusts have also agreed to assume certain liabilities for other third party claims up to 80% of the transaction proceeds. Neither the Trusts nor the Consortium is aware of any such third party claims and the Consortium is further protected from such claims by the secured nature of the convertible debt instrument in which it is investing.

[1] Includes Gregg Davis restricted stock
[2] Includes Gregg Davis and management team investments

($ in millions)

VIII. Management Incentives

Management will be provided with retention and performance incentives consisting of restricted common stock valued at $7mm set aside by the Consortium (which will retain voting control of such stock), options to acquire 5% of DPC (on a fully diluted basis) at an exercise price equal to the transaction value and options to acquire 5% of DPC (on a fully diluted basis) at an exercise price equal to 2.5 times the transaction value. The restricted stock will vest immediately and the options will vest ratably over five years. Senior management, geologists, geophysicists, engineers and landmen are also incentivized with overriding royalties on producing wells that DPC generates. Such overriding royalties are up to 3% of net production revenue and burden all partners in a well. DPC is burdened by such royalties only to the extent of its working interest. Senior management and key employees will be subject to employment agreements containing mutually agreeable non-compete provisions.

Equity Shares (on an as converted basis)

	Pre-Money		Post-Money		Effect of	Option Dilution	
	Equity	Percent	Equity	Percent	4.4% PIK	1.0x	2.5x
Evercore	$0.0	0.0%	$95.0	54.3%	55.0%	52.1%	49.5%
Sankaty	0.0	0.0	31.7	18.1	18.3	17.4	16.5
RMCP	0.0	0.0	31.7	18.1	18.3	17.4	16.5
Davis Family	72.6	91.2	0.0	0.0	0.0	0.0	0.0
Gregg Davis	7.0	8.8	7.0	4.0	3.7	3.5	3.4
Management[1]	0.0	0.0	7.0	4.0	3.4	8.5	13.1
Employees[2]	0.0	0.0	2.5	1.4	1.2	1.2	1.1
Total	$79.6	100.0%	$174.8	100.0%	100.0%	100.0%	100.0%

[1] Includes Gregg Davis restricted stock
[2] Includes Gregg Davis and management team investments

($ in millions)

IX. Reserve Values

DPC's reserves are assessed by Netherland, Sewell & Associates ("NSAI"), a leading reserve engineer. Reserves are assessed twice a year (January 1 and July 1) and are categorized under three broad categories: proved, probable and possible. Each category is then assigned a value known as the "PV10" which is the net present value of the expected net revenue of such reserves at the then prevailing NYMEX strip prices discounted at 10%. DPC's reserves and associated PV10s as of July 1, 2005 are set forth below. Detailed outputs from the July 1 reserve report are attached as Exhibits A and B (see "Rev Prelim Est #2 8-30.pdf" and "Rev Prelim Est GC 157 & 199 8-30.pdf").

Audited DPC Reserves as of July 1, 2005

	Volume (BCFE)			PV10 ($mm)		
	Onshore	Offshore	Total	Onshore	Offshore	Total
Proved	14.5	10.6	25.2	$59.2	$52.9	$112.1
Probable	11.1	10.1	21.2	47.1	71.9	119.1
Proved & Probable	25.6	20.7	46.4	$106.3	$124.8	$231.2
Possible	23.9	20.0	43.9	85.7	125.5	211.2
Total Reserves	49.5	40.8	90.3	$192.0	$250.3	$442.3

The NSAI estimates are based on Nymex strip pricing as below:

30-Jun-05 Nymex Strip Pricing

	Period Ending								
	31-Aug-05	30-Sep-05	31-Oct-05	30-Nov-05	31-Dec-05	31-Dec-06	31-Dec-07	31-Dec-08	Thereafter
Oil Price per Barrel	$56.50	$57.64	$58.30	$58.80	$59.12	$59.17	$57.93	$56.74	$56.29
Gas Price per mmbtu	6.98	7.08	7.10	7.72	8.21	7.99	7.89	7.89	7.89

The July 1 reserve report does not include Clipper, a significant offshore discovery made in November 2005. Pioneer (the operator and majority owner of Clipper) and DPC estimate the size of Clipper's reserves to be 10-30mm BOE (or 60-180 BCFE). South River Exploration has reviewed Clipper's well log and seismic data and has estimated its reserves at 12mm BOE and the Company's interest at 17.3 BCFE with a PV10 of $54.8mm (after all anticipated capital expenditures and priced at 30-Jun-05 Nymex strip). The calculation of Clipper's PV10 value is included in Appendix B.

As noted above, DPC's proved and probable reserves as of July 1, 2005 had a PV10 of $231mm. As outlined below, if the probable reserves associated with the Clipper discovery are taken into account, DPC's proved and probable reserves as of July 1, 2005, would have been 63.7 BCFE and would have had a PV10 of $286mm. This adjustment does not take into account depletion or any other discoveries which have occurred since July 1, 2005.

Adjusted DPC Reserves (including Clipper)

	BCFE	PV10 ($mm)
NSAI 7/1 Proved and Probable Reserves	46.4	$231.2
Clipper Adjustment	17.3	54.8
Adjusted Proved and Probable Reserves	63.7	$286.0

($ in millions, except per unit data) - 9 - RED MOUNTAIN CAPITAL PARTNERS LLC

X. Historical and 2006 Budget

DPC's revenue and EBITDA increased significantly in 2005 due to higher oil and gas prices and new production from Bellis even though it was shut down in August due to hurricanes Katrina and Rita. Revenue and EBITDA are expected to increase further in 2006 as Bellis returns to production and Lorien commences production. EBITDA declined in 2004 due to reduced production in Texas and an increase in G&A costs related to re-establishing DPC's presence in the Rockies (new offices and additional employees). Capital expenditures increased in 2005 due to completion and development costs related to Bellis and Lorien. In 2006, capital expenditures will increase substantially as DPC invests in offshore prospect generation, completion and development expenditures associated with Lorien and Clipper and new initiatives in the Rockies. DPC's audited financial statements for 2003 and 2004 are attached as Exhibit C (see "Davis Petroleum_Combined Financial Statements December 31 2004 and 2003.pdf") and a detailed monthly schedule of the 2005 and 2006 budgets is included in Appendix C.

	2003A	2004A	2005E[1]	2006E[1]
Annual Production (mmcfe)	4,879.7	3,870.6	4,879.8	12,543.9
Average Daily Production (mcfe)	13,369.0	10,604.5	13,369.2	34,367.0
Peak Daily Production (mcfe)	NA	NA	16,725.8	51,946.0
Net Revenue	$31.9	$30.8	$40.1	$128.5
EBITDA	14.6	10.6	17.0	98.3
Capital Expenditures	26.3	24.7	43.6	99.8

XI. Five Year Financial Projections

Outlined below is a summary of RMCP's projections for the Company's financial performance through 2010. RMCP's projections are grounded in the Company's 2006 budget, discounted production estimates for the Company's proved and probable reserves provided by the Consortium's consulting engineer and substantial discounts (50% to 90% varying by region) to management's estimates for future production arising from possible reserves and undrilled prospects. The projections constrain production growth on a region by region basis to reflect differences in business outlook. In its projections, RMCP holds cash constant at approximately $33mm after 2006 and invests excess cash flow in capital expenditures. For 2006, oil and gas production is priced at the Nymex strip and, for 2007 and thereafter, oil is priced at $50 per barrel and gas is priced at $9 per mcf (generating a decline in 2007 EBITDA on increased production). RMCP believes that its financial projections are conservative. A detailed set of RMCP's financial projections and supporting assumptions is set forth in Appendix D. The results of a discounted cash flow and IRR analysis of RMCP's financial projections are set forth in Section XIII.

	2006	2007	2008	2009	2010
Annual Production (mmcfe)	12,543.9	13,327.7	15,229.1	18,473.2	21,529.6
Average Daily Production (mcfepd)	34,367.0	36,514.4	41,723.5	50,611.6	58,985.1
Net Revenue	$128.5	$111.3	$124.3	$150.9	$175.7
EBITDA	98.3	80.6	88.3	109.9	129.4
Capital Expenditures	99.8	60.5	63.8	78.9	93.5

[1] Projected revenue and EBITDA based on actual revenue through October 2005 and Nymex strip pricing thereafter

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XII. Acquisition Opportunities and Exit Scenarios

DPC has the potential to acquire additional oil and gas assets and RMCP expects the Company to pursue such acquisition opportunities as they arise. For example, in the last three years, DPC has evaluated the acquisition of Calpine's natural gas assets and Mariner Energy (which Carlyle/Riverstone acquired in the Enron bankruptcy). Such acquisitions may require additional capital which may be provided by the Consortium or from external sources.

The Consortium expects an IPO of DPC in two to five years to be a likely exit and/or liquidity scenario, subject to market conditions and other variables. There may also be opportunities to generate extraordinary dividends through refinancings or excess cash flow and to consider a strategic sale or merger of DPC.

XIII. Valuation and Investor Returns

RMCP has reviewed DPC's enterprise value in the context of similar publicly traded companies and companies that have been recently sold to strategic buyers. As illustrated below, DPC's post-money enterprise value is broadly in line with public market trading comparables based on 2004 actual and 2005 estimated EBITDA and 2004 year end proved reserve levels.

Public Market Valuation

		Enterprise	EV /EBITDA		Enterprise Value /	
Ticker	Company	Value[1]	2004A	2005E	Reserves[2]	PV10[3]
GDP	Goodrich Petroleum Corp.	$709.7	24.7x	18.5x	$7.01	2.93x
CRZO	Carrizo Oil & Gas Inc.	707.7	19.2	12.8	6.48	3.39
BEXP	Brigham Exploration Co.	621.3	10.7	7.7	5.12	2.11
PQUE	PetroQuest Energy Inc.	538.8	8.5	6.2	5.32	1.65
CPE	Callon Petroleum Co.	519.2	6.1	5.0	2.71	0.85
EPEX	Edge Petroleum Corp.	488.8	10.7	5.3	5.48	1.92
TMR	Meridian Resource Corp.	442.3	2.7	3.2	3.18	0.81
NEGI	National Energy Group Inc.	199.1	5.7	NA	0.85	0.44
TXCO	Exploration Co. of Delaware Inc.	190.0	10.5	8.1	5.01	2.36
MCF	Contango Oil & Gas Co.	168.1	68.6	NA	9.65	2.81
	Davis Petroleum Corp.	$157.2	14.8x	9.3x	$6.29	2.09x
High		$709.7	68.6x	18.5x	$9.65	3.39x
Median		504.0	10.6	7.0	5.22	2.02
Mean		458.5	16.7	8.4	5.08	1.93
Low		168.1	2.7	3.2	0.85	0.44

[1] Market data as of market close on 13-Jan-06
[2] $ of enterprise value per mcfe of 2004 year end proved reserves
[3] Enterprise value divided by PV10 of 2004 year end proved reserves

($ in millions, except per unit data) - 11 - RED MOUNTAIN CAPITAL PARTNERS LLC

Considering DPC's 2006 estimated EBITDA, DPC's adjusted post-money enterprise value represents a significant discount to such public market comparables. DPC's adjusted post-money enterprise value ($176mm) is 1.8x 2006 estimated EBITDA ($98mm). Because 2006 estimated EBITDA includes Bellis and Lorien scheduled production, DPC's adjusted post-money enterprise value includes $19mm of capital expenditures required to fund completion and development expenditures relating to such production.

The most comparable recent transaction in the merger market is the August 2005 acquisition of Gryphon Exploration Company, a well recognized Houston-based oil and gas exploration company operating in the GOM, by Woodside Petroleum Ltd., an Australian oil and gas company. Gryphon was formed in October 2000 with the backing of Warburg Pincus and grew over five years to include an experienced management team, a substantial inventory of exploration prospects and GOM lease acreage, net production of 30,000 mcfe/day and proved and probable reserves of 114 BCFE as of July 1, 2005. Woodside acquired Gryphon for a pre-money enterprise value of $297mm or $2.60 per mcfe of 2P reserves. DPC's pre-money enterprise value of $122mm or $1.92 per mcfe of 2P reserves (including Clipper) compares favorably to Gryphon's pre-money enterprise value.

As outlined below, DPC's post-money net asset value, taking into account only proved reserves and other tangible assets less debt, will be $160mm.

Included Reserves	Proved	+Probable	+Clipper
PV10 as of 1-Jul-05	$112.1	$231.2	$286.0
Cash	60.2	60.2	60.2
Value of Land in Undrilled Prospects	10.9	10.9	10.9
Value of Carried Interest in Sold but Undrilled Prospects	9.5	9.5	9.5
Value of Seismic Data	10.0	10.0	10.0
Gross Asset Value	$202.8	$321.9	$376.7
Senior Debt	20.0	20.0	20.0
Mezzanine Debt	22.6	22.6	22.6
Net Asset Value (before Convertible Debt)	$160.2	$279.3	$334.1
Transaction Value /NAV	1.09x	0.63x	0.52x

The transaction value ($175mm equity value at closing) is 1.1x DPC's post-money NAV including only proved reserves as of July 1, 2005. Taking into account proved and probable reserves (including the Clipper discovery), the transaction value is 0.5x DPC's post-money NAV. Taking into account an anticipated increase in proved and probable reserves since the July 1 reserve report, we believe the transaction value is less than 0.5x DPC's post-money net asset value.

($ in millions)

RMCP also performed discounted cash flow and IRR analyses of its five year financial projections at various commodity price points ranging from $60 per barrel of oil and $12 per mcf of gas to $40 per barrel of oil and $6 per mcf of gas (after 2006) and assuming an exit from the business at the end of 2010 at a range of enterprise values from 4x to 6x 2010 EBITDA (consistent with a potential IPO valuation). As outlined below, the net present value of RMCP's financial projections at a 12% discount rate, $50 per barrel of oil, $9 per mcf of gas and a 5x EBITDA terminal value suggests an enterprise value for DPC of $304mm which compares favorably to DPC's post-money enterprise value of $157mm.

Discounted Cash Flow Enterprise Value Analysis

Commodity Pricing	Terminal EBITDA Multiple: 4.0 x	4.5 x	5.0 x	5.5 x	6.0 x
$60 Oil, $12 Gas	$314.1	$363.0	$411.8	$460.7	$509.6
$50 Oil, $9 Gas	229.7	266.7	303.8	340.8	377.9
$40 Oil, $6 Gas	133.7	158.9	184.2	209.4	234.6

Based on RMCP's financial projections, the IRR for the Consortium's proposed investment is 28% assuming $50 per barrel of oil and $9 per mcf of gas (after 2006) and 18% assuming $40 per barrel of oil and $6 per barrel of gas (after 2006), in both cases assuming a 5x terminal EBITDA multiple.

Internal Rate of Return Analysis

Commodity Pricing	Terminal EBITDA Multiple: 4.0 x	4.5 x	5.0 x	5.5 x	6.0 x
$60 Oil, $12 Gas	29.2%	32.3%	35.0%	37.6%	40.0%
$50 Oil, $9 Gas	22.4	25.2	27.8	30.3	32.5
$40 Oil, $6 Gas	12.3	15.1	17.7	20.1	22.2

XIV. Downside Analyses

RMCP performed several different downside analyses including further delays in offshore production, further reductions in commodity prices and no new discoveries and production.

Delayed Offshore Production

The projections outlined above assume that Bellis and Lorien begin production in June 2006. RMCP's delayed offshore case assumes that Bellis and Lorien come online in September 2006. A three month delay in offshore cash flows will not require any additional primary capital and the delay is not material to the five year projections as the production associated with Bellis and Lorien will be realized within the five year time horizon.

Reduced Commodity Prices

The analysis outlined above reflects oil prices after 2006 in the range of $40 to $60 per barrel. In a downside analysis, RMCP calculated the minimum commodity price necessary to return its capital. Assuming Nymex pricing through 2006, commodity prices thereafter of $23.81 per barrel of oil and $3.97 per mcf of gas would still return investors' capital excluding fees and expenses (assuming the same

production projections and exit scenario). RMCP assumes, however, that in a low commodity price environment production growth will be further constrained and the breakeven commodity price should therefore be higher.

<u>No New Discoveries and Production</u>

The projections outlined above assume that there will only be new discoveries that allow the Company to grow production by an average annual rate of 15% after 2006 with different growth assumptions for each region in which the Company operates. This assumption reduces management's projections for new discoveries and associated production by 50% to 90% depending upon the region. In a downside analysis, RMCP assumed that future production would be generated exclusively from current proved and probable reserves and that there would be no new production and no associated investments in seismic, land or new wells. In that scenario, assuming a 5x EBITDA terminal value and $50 per barrel of oil and $9 per mcf of gas after 2006, the Consortium's investment would have an IRR of 5%.

Appendix A.
Personnel Overview

I. Executive Management

Gregg Davis, President & CEO

Mr. Davis has over 20 years experience in the oil and gas industry and is the third generation to manage the Davis family's oil and gas business. He has a strong understanding of the petroleum exploration and production process having worked in each of DPC's departments over the years including land, geology, geophysics, engineering and marketing and transportation. He worked closely with his father and his father's executives to gain a strong sense of how to build and operate a successful exploration enterprise. Mr. Davis received a B.A. from the University of Southern California where his studies included geology, oceanography and business administration. He serves on the board of the American Petroleum Institute and is a member of the Young Presidents' Organization.

George Canjar, Executive Vice President & COO

Mr. Canjar has over 22 years of experience in the oil and gas industry. He joined DPC in 2002 from Carrizo Oil & Gas where he served as Vice President of Exploration and Development. At Carrizo, Mr. Canjar developed the prospect portfolio and concurrently performed risk assessment and early data integration to optimize investment and future value of the drilling programs. In addition, he actively managed company prospect staff, prospect generation shops, company operations and joint venture partners. Previously, he served in a variety of technical and managerial positions at Shell Oil Company, including Technical Manager of Geology & Geophysics and Team Leader for numerous integrated project execution groups. Mr. Canjar received a B.S. in Geology from the Colorado School of Mines and is a certified Petroleum Engineer and Registered Geologist.

Mike McGuire, Executive Vice President & Head of Rocky Mountain Operations

Mr. McGuire has over 32 years of experience in the oil and gas industry. He joined DPC in 2004 from Prima Energy Corporation where he served as Executive Vice President of Exploration. He began his career with Cities Service E&P research in 1973. In 1978, he joined Amoco Production Company where he managed the exploration and development effort for the Rocky Mountain states and Africa. In 1986, he established a consulting company that completed domestic and international projects for Amoco International, NERCO, Gas Research Institute, Ecopetrol Columbia, NOMECO, Snyder Oil and others. In 1998, he joined Prima Energy Corporation which was sold to PetroCanada in 2004. Mr. McGuire received a B.S. in Geology from University of Nebraska and an M.S. in Geology from Oklahoma State University and is a certified Petroleum Geologist. Mr. McGuire has served as an Associate Editor of the American Association of Petroleum Geologists, and serves on the Board of Directors for the Potential Gas Committee and as Chairman of the Coalbed Methane Committee and Vice President of the Western Region.

II. Gulf Coast Onshore Team

Name	Title	Joined Davis	Experience		Education
			Years	Prior	
Jerry Durtsche	Explorationist	1999	30	Texaco, Superior Oil, Ladd Petroleum	Ph.D., Geophysics, New Mexico Institute Of Mining & Technology; B.S., Geology, Arizona State University
Bruce Lowry	Explorationist	1996	25	Marathon Oil, Amerada Hess	M.S., Geology, University of Rhode Island
Vincent Manara	Explorationist	1996	23	Getty Oil, various independents	B.S., Geology, Old Dominion
George Parker	Explorationist	2000	20	Various independents	B.S., Geology, Tulane
J. Michael Gregory	Land Manager	1996	25	Getty Oil, ARCO, Petro-Lewis	B.B.A./P.L.M., University of Texas
Bud Gholson	Landman	2002	22	Mitchell Oil, Getty Oil	B.B.A./P.L.M., University of Texas
Alan Martinkewiz	Landman	2001	22	Amerada Hess, various independents	M.B.A., Centenary College; B.B.A./P.L.M., University of Oklahoma
David Hinners	Engineering Manager	2003	28	Antara Resources, Texoil	B.S., Petroleum Engineering, LSU
Gregory Schneider	Prod. Ops. Manager	2000	20	Transco, Enron, Howell Petroleum, Rainbow Resources, others	M.S., University of St. Thomas; B.A., Business Engineering, University of Texas

III. Gulf of Mexico Offshore Team

Name	Title	Joined Davis	Experience: Years	Experience: Prior	Education
John Bellis	Senior Explorationist	2001	20	ARCO, Vastar, various independents	M.S., Geology, University of New Orleans; B.S., Geology, LSU
Michael Clark	Senior Explorationist	2001	16	ARCO, Vastar	M.S., B.S., Geology, Kansas State University
Mark Gillespie	Senior Explorationist	2001	23	ARCO, Vastar	B.S., Geophysics, Bowling Green
John Sansbury	Business Dev. Manager	2001	24	ARCO, Vastar	J.D., Univ. of Mississippi; B.A., Political Science, Mississippi State University
Ed Stengel	Land Manager	2001	21	ARCO, Vastar	B.S., Mineral Land Management, University of Colorado

IV. Rocky Mountain Team

Name	Title	Joined Davis	Experience: Years	Experience: Prior	Education
Will von Drehle	Chief Explorationist	1980	30	EOG Resources, Magnolia Oil, Amoco, Davis Oil	M.S., B.S., Geology, Florida State University
John Morel	Chief Explorationist	2002	22	Williams-Gary Oil, Basin Exploration, various independents	Ph.D., Geology, University of Wyoming; B.S., Physics, IIT
Michael Bryan	Explorationist	2002	25	Texaco, Cabot Oil & Gas, Columbia Gas Development	B.S., Geology, California State University
Lisa Morris	Explorationist	2004	7	Prima Energy	B.S., Geology, University of Missouri
Russell Spenser	RM Land Manager	1995	32	Davis Oil, Phillips, independent	B.A., Baylor University
Mark Goldberg	Land Manager	1983	22	Davis Petroleum	B.A., University of Colorado
Michael Purfield	Operations Manager	2004	22	Prima, ARCO, PMC	B.S., Chemical Engineering, Colorado School of Mines; M.B.A., UCLA
Stephen Smith	Consulting Engineer	1997	30	Various independents, consultant	B.S., Engineering, Colorado School of Mines

V. Oklahoma Team

Name	Title	Joined Davis	Experience: Years	Experience: Prior	Education
Mark Specketer	Chief Explorationist	2004	27	Chesapeake, Grace Petroleum, Texas Oil and Gas	B.S., Northwest Missouri State University
Mike Ensley	Explorationist	2004	38	Phillips, Cities Service, Vintage Petroleum, Santa Fe Energy, Thomas C. Mueller	
David Read	Explorationist	2004	27	Chevron, Mapco, CNG, various independents, consultant	
Danny Wilson	Explorationist	2004	35	Texas, Tenneco, Anadarko	

Appendix B.
Clipper Projections

	2006	2007	2008	2009	2010	2011	2012	2013	2014	Total[1]
Production										
Oil (mbo)	0.0	0.0	192.6	561.2	663.0	490.3	324.2	212.3	123.5	2,567.1
Gas (mmcf)	0.0	0.0	115.5	336.7	397.8	294.2	194.5	127.4	74.1	1,540.3
Total Production (mmcfe)	0.0	0.0	1,271.0	3,703.8	4,376.1	3,236.3	2,139.7	1,401.2	814.9	16,942.9
30-Jun-05 Nymex Strip Pricing										
Price per Barrel of Oil	$59.17	$57.93	$56.74	$56.29	$56.29	$56.29	$56.29	$56.29	$56.29	
Price per mcf of Gas	7.99	7.89	7.89	7.89	7.89	7.89	7.89	7.89	7.89	
Pricing Differentials										
Per Barrel of Oil	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	
Per mcf of Gas	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	
Net Pricing										
Price per Barrel of Oil	$57.67	$56.43	$55.24	$54.79	$54.79	$54.79	$54.79	$54.79	$54.79	$54.82
Price per mcf of Gas	7.19	7.09	7.09	7.09	7.09	7.09	7.09	7.09	7.09	7.09
Revenue										
Oil	$0.0	$0.0	$10.6	$30.7	$36.3	$26.9	$17.8	$11.6	$6.8	$140.7
Gas	0.0	0.0	0.8	2.4	2.8	2.1	1.4	0.9	0.5	10.9
Total Revenue	$0.0	$0.0	$11.5	$33.1	$39.1	$29.0	$19.1	$12.5	$7.3	$151.7
Operating Expenses	0.0	0.0	1.1	2.3	2.6	2.1	1.6	1.2	1.0	11.9
Capital Expenditures	4.5	16.0	1.3	15.3	0.0	0.0	0.0	0.0	0.0	37.2
Net Cash Flow	($4.5)	($16.0)	$9.1	$15.6	$36.5	$26.8	$17.5	$11.3	$6.3	$102.6
PV10	$54.8									

1 Clipper production continues post-2014 eventually reaching 17.3 BCFE of total production

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Appendix C.

2005 & 2006 Monthly Cash Flow Statements

I. Key Assumptions

§ Based on Management's monthly budgets

§ November and December 2005 production priced at 11-Nov-05 Nymex strip with Management price differentials

§ 2006 production priced at 16-Dec-05 Nymex strip with Management price differentials

§ Bellis comes back online and Lorien initiates production in June 2006

II. 2005 Monthly Actual and Projected Cash Flows

	Actual										Projected	
	January	February	March	April	May	June	July	August	September	October	November	December
OPERATIONS												
Production												
Oil (mbo)	7.4	9.8	11.7	14.4	14.9	13.9	22.7	24.6	21.4	8.9	12.0	12.2
Gas (mmcfe)	231.3	263.7	271.7	313.6	387.3	377.7	363.0	360.7	348.8	263.1	316.1	339.2
Total Production (mmcfe)	275.6	322.4	342.0	400.0	476.6	461.4	499.0	508.5	477.2	316.8	387.8	412.5
Cash Inflows from Operations												
Revenue	$2.0	$2.2	$2.3	$2.9	$3.6	$3.3	$3.8	$4.1	$4.3	$3.0	$4.4	$4.3
Overriding Royalty Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hedge Income (Losses)	0.0	(0.0)	(0.0)	(0.2)	(0.1)	0.1	(0.2)	(0.3)	(1.2)	0.0	0.0	0.0
Total Cash Inflows from Operations	$2.0	$2.2	$2.3	$2.7	$3.6	$3.4	$3.6	$3.8	$3.0	$3.1	$4.4	$4.3
Well Operating Expenses	0.3	0.7	0.4	0.4	0.4	0.4	0.4	0.6	0.5	0.6	0.7	0.7
General & Administrative Expenses	1.0	1.1	1.0	1.1	1.4	1.6	1.0	1.2	1.2	1.6	1.6	1.6
EBITDA	$0.7	$0.4	$0.8	$1.2	$1.8	$1.5	$2.2	$2.0	$1.4	$1.0	$2.2	$2.0
Financing Fees	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.0	0.0	0.0	0.0
Transaction & Other Fees	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Expense /(Income)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hedging Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest Expense	0.0	0.1	0.5	0.0	0.2	0.7	0.1	0.1	0.9	0.1	0.2	1.3
Cash Flow from Operations	$0.7	$0.3	$0.3	$1.2	$1.6	$0.8	$1.8	$1.8	$0.5	$0.8	$2.0	$0.7
CAPITAL EXPENDITURES												
Undeveloped Acreage Costs												
Rentals	$0.0	$0.0	$0.2	$0.0	$0.1	$0.1	$0.1	$0.1	$0.0	($0.1)	$0.0	$0.1
Land Costs net of Recovery	0.3	0.2	(0.1)	0.2	0.3	(0.7)	0.6	0.3	(0.5)	(2.2)	1.1	0.3
Seismic Costs	0.0	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.6
Total Undeveloped Acreage Costs	$0.4	$0.4	$0.2	$0.4	$0.4	($0.6)	$0.7	$0.4	($0.4)	($2.2)	$1.4	$1.0
Drilling Costs												
Bellis	$0.0	$0.0	$0.0	$0.0	$0.1	($0.0)	$0.5	$0.9	$1.0	$0.8	$0.1	$0.0
Lorien	0.3	1.0	0.4	0.3	0.6	1.4	0.8	0.5	(0.0)	(0.1)	0.0	0.0
Clipper	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	0.4	0.2	0.0
Other Offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas, Louisiana & Oklahoma	0.6	1.0	1.2	1.2	0.7	0.5	0.3	0.6	0.5	0.8	2.3	1.0
Rocky Mountains	0.1	0.2	0.2	0.3	0.1	0.0	0.0	0.2	0.1	0.0	0.3	0.1
Total Drilling Costs	$1.0	$2.1	$1.8	$1.8	$1.4	$3.1	$1.6	$2.2	$1.6	$2.0	$2.8	$1.1
Completion & Facility Costs												
Bellis	$1.0	$0.4	$0.7	$0.6	$1.9	$2.2	$1.3	$1.3	$0.4	$0.4	$0.3	$0.0
Lorien	0.0	0.0	0.1	0.1	0.0	0.0	0.2	0.2	1.2	0.6	1.2	0.0
Clipper	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas, Louisiana & Oklahoma	0.0	0.0	0.0	0.0	0.0	0.3	0.2	0.4	0.5	0.3	0.3	0.7
Rocky Mountains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	(0.0)	0.1	0.1
Total Completion & Facility Costs	$1.0	$0.4	$0.8	$0.7	$1.9	$2.5	$1.7	$1.9	$2.1	$1.2	$1.9	$0.8
Other Well Costs & Inflation	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.4	0.2	0.4	0.5	0.2
Total Well Costs	$2.0	$2.5	$2.6	$2.5	$3.5	$5.6	$3.4	$4.5	$3.9	$3.6	$5.3	$2.0
Furniture, Fixtures & Equipment	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Capital Expenditures	$2.4	$3.0	$2.9	$2.9	$3.9	$5.0	$4.1	$4.9	$3.5	$1.4	$6.7	$3.0
FINANCING ACTIVITIES												
EPL Financing	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Sankaty Bridge Loan	0.0	0.0	0.0	0.0	0.0	5.0	0.0	5.0	5.0	0.0	5.0	0.0
Equity Infusion	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL CASH FLOW	($1.7)	($2.7)	($2.6)	($1.6)	($2.3)	$0.8	($2.3)	$1.9	$2.0	($0.6)	$0.3	($2.3)
Beginning Cash	$4.3	$2.6	($0.1)	($2.7)	($4.3)	($6.6)	($5.8)	($8.1)	($6.1)	($4.2)	($4.7)	($4.4)
Ending Cash	2.6	(0.1)	(2.7)	(4.3)	(6.6)	(5.8)	(8.1)	(6.1)	(4.2)	(4.7)	(4.4)	(6.7)

($ in millions)

III. 2006 Monthly Projected Cash Flows

	Projected											
	January	February	March	April	May	June	July	August	September	October	November	December
OPERATIONS												
Production												
Oil (mbo)	13.2	14.4	14.2	16.3	15.5	69.7	123.3	145.8	145.4	145.5	146.0	145.5
Gas (mmcfe)	382.7	397.3	401.9	454.9	444.7	526.9	589.8	657.7	659.9	676.9	696.4	686.3
Total Production (mmcfe)	461.7	483.9	487.3	552.6	537.6	945.1	1,329.6	1,532.3	1,532.5	1,549.8	1,572.2	1,559.3
Cash Inflows from Operations												
Revenue	$5.8	$6.1	$6.2	$5.7	$5.4	$9.3	$13.0	$15.0	$15.0	$15.2	$15.8	$15.9
Overriding Royalty Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hedge Income (Losses)	(0.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Cash Inflows from Operations	$5.3	$6.1	$6.2	$5.7	$5.4	$9.3	$13.0	$15.0	$15.0	$15.2	$15.8	$15.9
Well Operating Expenses	0.8	0.9	0.9	0.8	0.8	1.1	1.2	1.4	1.4	1.4	1.5	1.7
General & Administrative Expenses	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.7
EBITDA	$3.2	$4.0	$4.0	$3.6	$3.4	$6.9	$10.4	$12.3	$12.3	$12.5	$13.0	$12.6
Financing Fees	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transaction & Other Fees	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Expense /(Income)	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hedging Costs	0.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interest Expense	0.2	0.1	0.6	0.1	0.1	0.6	0.1	0.1	0.6	0.1	0.1	0.6
Cash Flow from Operations	$0.5	($5.1)	$2.6	$3.5	$3.3	$6.3	$10.3	$12.2	$11.7	$12.4	$12.9	$11.9
CAPITAL EXPENDITURES												
Undeveloped Acreage Costs												
Rentals	$0.1	$0.2	$0.4	$0.2	$0.2	$0.0	$0.1	$0.0	$0.0	$0.1	$0.0	$0.1
Land Costs net of Recovery	(1.0)	(0.2)	(0.4)	5.3	5.0	0.0	(0.2)	0.3	0.7	0.3	(0.2)	0.8
Seismic Costs	0.0	3.7	2.6	0.4	0.4	2.3	0.0	0.0	2.3	0.0	0.0	2.3
Total Undeveloped Acreage Costs	($1.0)	$3.7	$2.6	$5.8	$5.5	$2.3	($0.1)	$0.4	$2.9	$0.5	($0.1)	$3.2
Drilling Costs												
Bellis	$0.3	$0.1	$1.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Lorien	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Clipper	1.4	5.4	1.8	0.0	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Offshore	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0
Texas, Louisiana & Oklahoma	6.0	0.4	1.9	2.2	0.7	0.1	0.1	1.0	0.0	2.9	0.7	0.0
Rocky Mountains	0.4	0.0	0.3	0.1	0.4	0.7	0.5	0.6	1.2	1.3	0.5	1.7
Total Drilling Costs	$8.1	$6.3	$6.4	$2.3	$5.0	$0.8	$0.7	$1.6	$1.3	$5.2	$1.2	$1.7
Completion & Facility Costs												
Bellis	$0.6	$0.5	$3.7	$0.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Lorien	1.1	2.7	7.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Clipper	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas, Louisiana & Oklahoma	0.7	0.4	0.6	0.5	1.6	0.3	0.3	0.5	0.1	0.2	0.2	0.5
Rocky Mountains	0.8	0.3	0.5	0.0	0.2	0.2	0.2	0.3	0.2	0.4	0.1	0.1
Total Completion & Facility Costs	$3.2	$3.9	$11.8	$0.8	$1.7	$0.5	$0.5	$0.8	$0.3	$0.6	$0.4	$0.7
Other Well Costs & Inflation	2.2	0.3	0.8	0.7	0.7	0.3	0.3	0.6	0.4	1.2	0.4	0.6
Total Well Costs	$13.5	$10.5	$19.0	$3.8	$7.4	$1.7	$1.5	$3.0	$1.9	$7.0	$2.0	$2.9
Furniture, Fixtures & Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Capital Expenditures	$12.5	$14.2	$21.6	$9.6	$13.0	$4.0	$1.4	$3.4	$4.9	$7.5	$1.9	$6.1
FINANCING ACTIVITIES												
EPL Financing	$4.0	$0.0	$0.0	$0.0	$0.0	$0.0	$3.0	$0.0	$0.0	$0.0	$0.0	$0.0
Sankaty Bridge Loan	(20.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Equity Infusion	95.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL CASH FLOW	$67.0	($19.2)	($19.0)	($6.1)	($9.7)	$2.3	$11.9	$8.8	$6.8	$5.0	$11.0	$5.8
Beginning Cash	($6.7)	$60.2	$41.0	$22.0	$16.0	$6.3	$8.6	$20.5	$29.2	$36.0	$41.0	$52.0
Ending Cash	60.2	41.0	22.0	16.0	6.3	8.6	20.5	29.2	36.0	41.0	52.0	57.7

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Appendix D.

Five Year Annual Projected Cash Flows

I. 4Q-2005 and 2006 Assumptions

§ Based on Management's monthly budgets

§ November and December 2005 production priced at 11-Nov-05 Nymex strip with Management price differentials

§ 2006 production priced at 16-Dec-05 Nymex strip with Management price differentials

§ Bellis comes back online and Lorien initiates production in June 2006

§ No income taxes in 2005

§ 2006 taxed at 38% rate, effective tax rate of 25% of EBITDA

§ 2006 tax write-offs calculated as the sum of deductible expenses provided by Management and discounted by the Consortium's consulting engineer, South River Exploration, plus interest expenses, financing fees, transaction fees, hedging costs and other expenses

II. 2007 through 2010 Assumptions

§ Based on Management and NSAI projections discounted by South River Exploration and coupled with regional top-down growth rate constraints

§ $50 per barrel of oil and $9 per mcf of gas with Management price differentials

§ 2006 year end cash held as buffer to fund excess capital expenditures, excess cash flow invested in new offshore well costs

§ Clipper initiates production in 2008

§ Pro forma entity is taxed at a 38% rate, after tax write-offs of 25% of revenue plus interest expense, effective tax rate of 23-24% of EBITDA

§ Working capital increases by 6% of annual revenue change

§ $20mm bank loan and $22.6mm Sankaty loan are outstanding for the length of the projections and earn interest at 6.6% and 11.0% respectively, interest reported net of 2.0% return on average cash balance

III. Five Year Annual Projected Cash Flows

	2005	2006	2007	2008	2009	2010
OPERATIONS						
Production						
Oil (mbo)	173.9	994.8	1,045.6	1,220.0	1,419.0	1,578.8
Gas (mmcfe)	3,836.3	6,575.3	7,054.1	7,909.2	9,959.5	12,056.8
Total Production (mmcfe)	4,879.8	12,543.9	13,327.7	15,229.1	18,473.2	21,529.6
Cash Inflows from Operations						
Revenue	$40.0	$128.5	$111.3	$124.3	$150.9	$175.7
Overriding Royalty Interests	0.0	0.0	0.0	0.0	0.0	0.0
Hedge Income (Losses)	(1.7)	(0.5)	0.0	0.0	0.0	0.0
Total Cash Inflows from Operations	$38.3	$128.0	$111.3	$124.3	$150.9	$175.7
Well Operating Expenses	6.0	13.9	10.2	14.7	18.4	22.5
General & Administrative Expenses	15.4	15.8	20.6	21.3	22.5	23.9
EBITDA	$17.0	$98.3	$80.6	$88.3	$109.9	$129.4
Financing Fees	0.4	0.0	0.0	0.0	0.0	0.0
Transaction & Other Fees	0.0	2.5	0.0	0.0	0.0	0.0
Other Expense /(Income)	(0.2)	0.8	0.0	0.0	0.0	0.0
Hedging Costs	0.0	9.0	0.0	0.0	0.0	0.0
Interest Expense, Net	4.2	3.5	3.1	3.1	3.1	3.1
Income Taxes	0.0	24.1	18.9	20.6	26.2	31.3
Change in Working Capital	0.0	0.0	(1.0)	0.8	1.6	1.5
Cash Flow from Operations	$12.6	$58.4	$59.6	$63.8	$78.9	$93.5
CAPITAL EXPENDITURES						
Undeveloped Acreage Costs						
Rentals	$0.7	$1.4	$0.9	$0.9	$1.0	$1.1
Land Costs net of Recovery	(0.1)	10.5	6.5	0.1	4.3	6.6
Seismic Costs	1.4	13.9	10.4	11.2	11.9	13.1
Net Undeveloped Acreage Costs	$2.0	$25.9	$17.8	$12.3	$17.1	$20.8
Well Costs						
Bellis	$13.7	$6.8	$3.3	$0.1	$0.1	$0.0
Lorien	8.7	11.7	0.0	0.0	0.0	0.6
Clipper	1.8	12.8	16.0	1.3	15.3	0.0
Other Offshore	0.0	1.4	0.0	18.5	10.3	37.4
Total Offshore	$24.2	$32.7	$19.3	$19.9	$25.6	$38.0
Texas, Louisiana & Oklahoma	13.5	21.9	5.7	7.8	8.9	11.2
Rocky Mountains	1.8	11.0	13.7	19.8	23.0	19.0
Other Well Costs & Inflation	1.8	8.3	4.0	4.1	4.3	4.5
Total Well Costs	$41.3	$73.9	$42.7	$51.6	$61.8	$72.7
Furniture, Fixtures & Equipment	0.2	0.0	0.0	0.0	0.0	0.0
Total Capital Expenditures	$43.6	$99.8	$60.5	$63.8	$78.9	$93.5
FINANCING ACTIVITIES						
EPL Financing	$0.0	$7.0	$0.0	$0.0	$0.0	$0.0
Sankaty Bridge Loan	20.0	(20.3)	0.0	0.0	0.0	0.0
Equity Infusion	0.0	95.3	0.0	0.0	0.0	0.0
Cash Dividends	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL CASH FLOW	($11.1)	$40.6	($0.8)	$0.0	($0.0)	($0.0)
Beginning Cash	$4.3	($6.8)	$33.9	$33.0	$33.0	$33.0
Ending Cash	(6.8)	33.9	33.0	33.0	33.0	33.0

($ in millions)

IV. Offshore Annual Projected Cash Flows

	2005	2006	2007	2008	2009	2010	2007-2010 Assumption
OPERATIONS							
Oil Production (mbo)							
Bellis	27.5	437.3	400.9	344.6	226.1	36.6	81% of NSAI Proved & Probable per South River Exploration
Lorien	0.0	360.0	378.2	111.8	13.6	0.3	86% of NSAI Proved & Probable per South River Exploration
Clipper	0.0	0.0	0.0	192.6	561.2	663.0	60% of Management Projections per South River Exploration
New Offshore	0.0	0.0	0.0	223.6	176.4	394.6	In aggregate, a 86% discount to Management Projections
Total Oil Production	27.5	797.3	779.1	872.6	977.3	1,094.6	Growth constrained to 12% per year after 2007
Gas Production (mmcf)							
Bellis	13.9	262.4	253.9	222.7	146.7	23.8	81% of NSAI Proved & Probable per South River Exploration
Lorien	0.0	576.0	512.8	138.9	16.9	0.4	86% of NSAI Proved & Probable per South River Exploration
Clipper	0.0	0.0	0.0	115.5	336.7	397.8	60% of Management Projections per South River Exploration
New Offshore	0.0	0.0	0.0	381.6	461.4	655.1	In aggregate, a 87% discount to Management Projections
Total Gas Production	13.9	838.3	766.7	858.7	961.8	1,077.2	Growth constrained to 12% per year after 2007
Total Production (mmcfe)	179.0	5,621.9	5,441.3	6,094.3	6,825.6	7,644.7	
Price per Barrel of Oil							
Bellis	$51.57	$55.62	$44.16	$44.16	$44.16	$44.16	0.92x Oil Adjustment Factor, $2.00 price differential
Lorien	NM	58.07	44.16	44.16	44.16	44.16	0.92x Oil Adjustment Factor, $2.00 price differential
Clipper	NM	NM	NM	44.62	44.62	44.62	0.92x Oil Adjustment Factor, $1.50 price differential
New Offshore	NM	NM	44.16	44.16	44.16	44.16	0.92x Oil Adjustment Factor, $2.00 price differential
Weighted Average Price per Barrel of Oil	$51.57	$56.73	$44.16	$44.26	$44.42	$44.44	
Price per mcf of Gas							
Bellis	$5.16	$10.03	$9.84	$9.84	$9.84	$9.84	1.20x BTU Inflator, $0.80 price differential
Lorien	NM	10.03	9.84	9.84	9.84	9.84	1.20x BTU Inflator, $0.80 price differential
Clipper	NM	NM	NM	8.20	8.20	8.20	$0.80 price differential
New Offshore	NM	NM	8.20	8.20	8.20	8.20	$0.80 price differential
Weighted Average Price per mcf of Gas	$5.16	$10.03	$9.84	$8.89	$8.48	$8.24	
Oil Revenue							
Bellis	$1.4	$24.3	$17.7	$15.2	$10.0	$1.6	
Lorien	0.0	20.9	16.7	4.9	0.6	0.0	
Clipper	0.0	0.0	0.0	8.6	25.0	29.6	
New Offshore	0.0	0.0	0.0	9.9	7.8	17.4	
Total Oil Revenue	$1.4	$45.2	$34.4	$38.6	$43.4	$48.6	
Gas Revenue							
Bellis	$0.1	$2.6	$2.5	$2.2	$1.4	$0.2	
Lorien	0.0	5.8	5.0	1.4	0.2	0.0	
Clipper	0.0	0.0	0.0	0.9	2.8	3.3	
New Offshore	0.0	0.0	0.0	3.1	3.8	5.4	
Total Gas Revenue	$0.1	$8.4	$7.5	$7.6	$8.2	$8.9	
Total Revenue	$1.5	$53.6	$41.9	$46.3	$51.6	$57.5	
Well Operating Expenses							
Bellis	$0.3	$1.1	$1.2	$1.1	$0.9	$0.2	81% of NSAI Proved & Probable per South River Exploration
Lorien	0.0	1.4	1.3	0.5	0.1	0.0	86% of NSAI Proved & Probable per South River Exploration
Clipper	0.0	0.0	0.0	1.1	2.3	2.6	60% of Management Projections per South River Exploration
New Offshore	0.0	0.0	0.0	2.0	1.8	3.5	Average Percentage of Revenue for Bellis, Lorien and Clipper
Total Well Operating Expenses	$0.3	$2.5	$2.5	$4.7	$5.1	$6.3	
General & Administrative Expenses	1.8	2.7	3.5	3.8	4.3	4.8	Revenue weighted average of 2005 and 2006 percentages of revenue
EBITDA	($0.6)	$48.4	$36.0	$37.8	$42.3	$46.4	
CAPITAL EXPENDITURES							
Undeveloped Acreage Costs							
Rentals	$0.2	$0.5	$0.4	$0.4	$0.5	$0.5	2006 Percentage of Revenue Held Constant
Land Costs	0.0	10.0	7.8	8.6	9.6	10.7	2006 Percentage of Revenue Held Constant
Seismic Costs	0.9	10.1	7.9	8.7	9.7	10.9	2006 Percentage of Revenue Held Constant
Total Undeveloped Acreage Costs	$1.1	$20.6	$16.1	$17.8	$19.8	$22.1	
Land Cost Recovery	0.1	0.0	2.1	2.3	2.6	2.9	Assumes less than 1/7 of undeveloped acreage investments result in prospects
Net Undeveloped Acreage Costs	$1.0	$20.6	$14.0	$15.5	$17.3	$19.2	
Well Costs							
Bellis	$13.7	$6.8	$3.3	$0.1	$0.1	$0.0	100% of NSAI Proved & Probable
Lorien	8.7	11.7	0.0	0.0	0.0	0.6	100% of NSAI Proved & Probable
Clipper	1.8	12.8	16.0	1.3	15.3	0.0	100% of NSAI Proved & Probable
New Offshore	0.0	1.4	0.0	18.5	10.2	37.4	Excess Cash Flow from Operations
Other Well Costs and Inflation	0.0	0.0	0.0	0.0	0.0	0.0	Projection of 0 for 2005 and 2006 carried forward
Total Well Costs	$24.2	$32.7	$19.3	$19.9	$25.6	$38.0	
Total Capital Expenditures	$25.2	$53.4	$33.4	$35.4	$42.9	$57.2	

($ in millions, except per unit data) - 25 - RED MOUNTAIN CAPITAL PARTNERS LLC

V. Texas, Louisiana & Oklahoma Annual Projected Cash Flows

	2005	2006	2007	2008	2009	2010	2007-2010 Assumption
OPERATIONS							
Oil Production (mbo)							
Existing	146.4	192.8	206.3	91.2	61.8	44.6	100% of NSAI Proved and 50% of NSAI Probable per South River Exploration
New	0.0	0.0	5.8	131.5	172.1	200.9	In aggregate, a 71% discount to Management Projections
Total Oil Production	146.4	192.8	212.1	222.7	233.8	245.5	Growth constrained to 5% per year, except 2007 at 10% reflecting current activity
Gas Production (mmcf)							
Existing	3,771.7	5,444.7	2,230.7	1,097.6	729.0	511.5	100% of NSAI Proved and 50% of NSAI Probable per South River Exploration
New	0.0	0.0	3,758.4	5,190.9	5,874.0	6,421.7	In aggregate, a 69% discount to Management Projections
Total Gas Production	3,771.7	5,444.7	5,989.1	6,288.6	6,603.0	6,933.2	Growth constrained to 5% per year, except 2007 at 10% reflecting current activity
Total Production (mmcfe)	4,649.9	6,601.5	7,261.7	7,624.8	8,006.0	8,406.3	
Price per Barrel of Oil							
Existing	$52.57	$57.71	$47.06	$46.30	$45.87	$45.94	Price differentials provided by Management
New	NM	NM	47.06	46.30	45.87	45.94	Price differentials provided by Management
Weighted Average Price per Barrel of Oil	$52.57	$57.71	$47.06	$46.30	$45.87	$45.94	
Price per mcf of Gas							
Existing	$8.08	$11.17	$9.06	$8.79	$8.83	$8.84	Price differentials provided by Management
New	NM	NM	9.06	8.79	8.83	8.84	Price differentials provided by Management
Weighted Average Price per mcf of Gas	$8.08	$11.17	$9.06	$8.79	$8.83	$8.84	
Oil Revenue							
Existing	$7.7	$11.1	$9.7	$4.2	$2.8	$2.1	
New	0.0	0.0	0.3	6.1	7.9	9.2	
Total Oil Revenue	$7.7	$11.1	$10.0	$10.3	$10.7	$11.3	
Gas Revenue							
Existing	$30.5	$60.8	$20.2	$9.6	$6.4	$4.5	
New	0.0	0.0	34.0	45.6	51.9	56.8	
Total Gas Revenue	$30.5	$60.8	$54.2	$55.3	$58.3	$61.3	
Total Revenue	$38.2	$71.9	$64.2	$65.6	$69.0	$72.6	
Well Operating Expenses							
Existing	$5.6	$10.1	$2.4	$1.5	$1.3	$1.1	100% of NSAI Proved and 50% of NSAI Probable per South River Exploration
New	0.0	0.0	4.5	6.8	7.9	8.7	Average Revenue Percentage for Existing Wells
Total Well Operating Expenses	$5.6	$10.1	$6.9	$8.3	$9.2	$9.8	
General & Administrative Expenses	11.2	10.1	14.0	14.3	15.0	15.8	Average 2005 /2006 percentage of revenue due to mature business model
EBITDA	$21.3	$51.7	$43.4	$43.0	$44.8	$47.0	
CAPITAL EXPENDITURES							
Undeveloped Acreage Costs							
Rentals	$0.3	$0.4	$0.5	$0.5	$0.5	$0.6	Average 2005 /2006 percentage of revenue due to mature business model
Land Costs	3.8	2.0	4.1	4.1	4.4	4.6	Average 2005 /2006 percentage of revenue due to mature business model
Seismic Costs	0.5	3.5	2.0	2.0	2.1	2.2	Average 2005 /2006 percentage of revenue due to mature business model
Total Undeveloped Acreage Costs	$4.6	$5.9	$6.5	$6.6	$7.0	$7.4	
Land Cost Recovery	3.9	4.2	5.2	5.3	5.6	5.8	Average 2005 /2006 percentage of revenue due to mature business model
Net Undeveloped Acreage Costs	$0.7	$1.7	$1.3	$1.4	$1.4	$1.5	
Well Costs							
Existing	$13.5	$21.9	$0.6	$0.1	$0.0	$1.4	100% of NSAI Proved and 50% of NSAI Probable per South River Exploration
New	0.0	0.0	5.1	7.7	8.9	9.8	Average Revenue Percentage for Existing Wells
Other Well Costs and Inflation	1.8	5.5	4.0	4.1	4.3	4.5	Average 2005 /2006 percentage of revenue due to mature business model
Total Well Costs	$15.3	$27.5	$9.7	$11.9	$13.2	$15.7	
Total Capital Expenditures	$16.0	$29.2	$11.0	$13.2	$14.6	$17.2	

VI. Rocky Mountain Region Annual Projected Cash Flows

	2005	2006	2007	2008	2009	2010	2007-2010 Assumption
OPERATIONS							
Production							
Oil Production (mbo)	0.0	4.7	54.4	124.7	207.8	238.7	50% of Management Projections per South River Exploration
Gas Production (mmcf)	50.7	292.4	298.2	762.0	2,394.7	4,046.5	50% of Management Projections per South River Exploration
Total Production (mmcfe)	50.8	320.5	624.7	1,510.0	3,641.6	5,478.6	
Pricing							
Price per Barrel of Oil	$45.50	$53.48	$49.00	$49.00	$49.00	$49.00	Price differentials provided by Management
Price per mcf of Gas	$6.80	$9.18	$8.38	$8.39	$8.39	$8.39	Price differentials provided by Management
Revenue							
Oil	$0.0	$0.3	$2.7	$6.1	$10.2	$11.7	
Gas	0.3	2.7	2.5	6.4	20.1	34.0	
Total Revenue	$0.3	$2.9	$5.2	$12.5	$30.3	$45.7	
Well Operating Expenses	$0.1	$1.4	$0.8	$1.7	$4.2	$6.4	50% of Management Projections per South River Exploration
General & Administrative Expenses	2.3	2.9	3.1	3.2	3.2	3.3	100% of Managements Projections
EBITDA	($2.1)	($1.3)	$1.2	$7.6	$22.9	$36.0	
CAPITAL EXPENDITURES							
Undeveloped Acreage Costs							
Rentals	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	50% of Management Projections per South River Exploration
Land Costs net of Recovery	0.2	2.7	1.9	(5.1)	(1.6)	0.0	50% of Management Projections per South River Exploration
Seismic Costs	0.0	0.3	0.5	0.5	0.0	0.0	50% of Management Projections per South River Exploration
Net Undeveloped Acreage Costs	$0.4	$3.5	$2.4	($4.6)	($1.6)	$0.0	
Drilling, Facility and Completion Costs	$1.8	$11.0	$13.7	$19.8	$23.0	$19.0	50% of Management Projections per South River Exploration
Other Well Costs and Inflation	0.0	2.7	0.0	0.0	0.0	0.0	50% of Management Projections per South River Exploration
Total Well Costs	$1.8	$13.7	$13.7	$19.8	$23.0	$19.0	
Total Capital Expenditures	$2.2	$17.2	$16.0	$15.2	$21.4	$19.0	

($ in millions, except per unit data) - 26 - RED MOUNTAIN CAPITAL PARTNERS LLC